STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2003-914

March 18, 2004

MAINE NATURAL GAS CORPORATION
Proposed Tariff Revisions for Index and Fixed Price Option Rates and to Implement Gas Cost Reconciliation Mechanism
(35-A M.R.S.A. §§ 307 and 4706)

EXAMINER'S REPORT

NOTE: This Report contains the recommendation of the Hearing Examiner and is in draft order format. It does not constitute formal Commission action. Parties may file responses or exceptions to this Report on or before March 24, 2004. It is expected that the Commission will consider this report at its deliberative session on March 29, 2004.

I. SUMMARY

We approve Maine Natural Gas Corporation's (MNG or the Company) proposed changes to its Indexed and Fixed Price Options as described in this Order. We defer consideration of MNG's commodity reconciliation proposal until the Company indicates what ratemaking mechanism it proposes after March 31, 2004. We invite further comment on whether a review of MNG's revenue requirements and earnings is statutorily required if it wishes to devolve to traditional rate regulation.

II. BACKGROUND

A. Docket No. 96-786

On December 17, 1998, we approved an alternative rate plan for MNG (then named CMP Natural Gas). The plan included a 5-year base distribution rate freeze. Customers would choose the manner in which they wished to purchase gas from MNG, either under the Index Price Option (IPO), which offered a monthly price based on reported market futures price indexes, or under the Fixed Price Option (FPO), for which price was fixed for a prescribed term of between 3 and 24 months. In addition, recognizing that rates for the interstate pipelines that would serve the LDC were subject to FERC jurisdiction, we allowed MNG to seek rate adjustments for changed upstream pipeline capacity costs. Finally, we granted the Company authority to negotiate individual special rate contracts that vary from the Company's scheduled rates without regulatory review. MNG's rate plan expires March 31, 2004.

B. Procedural History

On December 12, 2003, pursuant to 35-A M.R.S.A. §§ 307 and 4706 and Chapter 120 of the Commission's Rules, Maine Natural Gas Corporation (MNG) filed proposed revisions to its Index Price Option (IPO) and Fixed Price Option (FPO) rate schedules, pages 20.0 and 20.1. MNG initially sought authorization to modify its IPO and FPO rate schedules as follows: 1) to reduce the offered time periods for its FPO offerings, which range from 3- to 24- months, to 6- and 12- months and to change the customer enrollment periods from monthly to semi-annually in September and March; 2) to remove the heating oil component in its commodity pricing formula and to set commodity price on a 100% gas plus upstream transportation index to better reflect natural gas costs; and 3) to initiate a gas cost reconciliation, or "true up," mechanism so that it may recover its actual gas costs associated with its IPO and FPO customers, but not gas costs associated with its negotiated special contracts. MNG argued that these changes are necessary due to changed price levels and volatility in the gas markets since its initial rate plan was approved.

The Commission issued Notice of this proceeding on December 19, 2003 and established an intervention date of January 6, 2004. The Staff issued Advisor's Data Request No. 1 on December 19, 2003.

At the request of the Hearing Examiner, Maine Natural Gas provided notice to all general service customers by separate mailing on December 22 indicating that MNG's request for rate changes and gas cost reconciliation was pending and that it sought implementation of a new formula for its IPO rate for effect January 1, 2004. The letter also advised customers to contact the Commission to participate in, or learn more about, this proceeding.

Because of the immediacy of the proposed implementation date for the proposed revised IPO, the Staff held a preliminary conference with MNG and OPA on December 23, 2003 to discuss with MNG the details of its filing and its requested implementation schedule. The Hearing Examiner granted MNG's request for protective order from the bench, and portions of the conference were held *in camera*.

MNG asked for a waiver of the 30-day statutory time period established in 35-A M.R.S.A. §307 to allow an earlier effective date for the revised IPO of January 1, 2004 to avoid incurring costs resulting from high gas market prices during its high volume sales months of January through March. We declined to approve the IPO formula changes on less than statutory notice at our December 31, 2003 deliberations because of insufficient time for Notice of this proceeding to customers. In addition, MNG had not yet provided full information about its past years of experience with this formula. Furthermore, we did not find MNG's reasons for requesting approval on less than statutory notice to constitute good cause.

An initial hearing among all parties and proposed interveners was held on January 6, 2004. Timely petitions to intervene were filed by the Office of the Public Advocate (OPA) and Bangor Gas Company (BGC). The Hearing Examiner granted intervention for OPA and BGC, the latter on a limited basis. BGC was granted discretionary intervention and is restricted to receiving only non-confidential information.

By Order Approving Changes to Index Rate Options dated January 13, 2004, the Commission authorized MNG to change its IPO to remove the heating oil component in its commodity pricing formula and to set the commodity price using the NYMEX gas futures only. The Commission also authorized MNG to include its hedged basis cost in its IPO rate calculation. The Commission did not address what rate MNG should use after the hedged contract period expired in March 2004.

MNG originally proposes that revised FPO rates and terms become effective on March 1, 2004 "to avoid a gap in the availability of the FPO rate." The Company later modified its request to seek final approval by April 1, 2004 along with its request for approval of reconciliation.

III. DESCRIPTION OF PROPOSALS

A. Index and Fixed Price Options

1. Remaining IPO Issue

In its January 13, 2004 decision the Commission allowed MNG to set IPO rates based on its contract to hedge basis risk. We did not reach a conclusion as to how MNG should determine the basis cost[1] to include in both IPO and FPO rates after that contract ends in March. MNG has proposed using the published projected monthly basis costs for Dracut. If the projected price for basis at Dracut is not published, MNG proposed to use projected basis at Tetco M3 (NY), adjusted for the different locations.

After reviewing the information provided, we will authorize MNG to calculate basis as it proposed. We considered requiring MNG to use an average of the historical basis at Dracut for similar months. However, because Dracut is a relatively new trading point, the historical data is limited and may not accurately represent the upcoming periods. We note that much of the published information for Dracut basis is provided to subscribers only and we will require that MNG be able to support its rates with information that may be publicly provided to its customers.

2. Fixed Price Option

MNG has proposed two changes to its fixed price option. The first is changing the formula to remove the oil component and to change how basis is determined. The second is to reduce the number of enrollment periods for the FPO and reduce the number of terms customers may sign up for. We discuss each separately.

a. Calculation of FPO Formula

[1] The basis cost can be thought of as similar to a delivery charge. Strictly speaking, it is the difference in cost between a central trading hub, in this case Henry Hub which is where NYMEX trades are priced, and the cost of gas at or near the LDC's service area. For MNG, Dracut Massachusetts appears to be the most relevant local cost point.

MNG proposes to make changes to its FPO calculation similar to the changes made in the IPO calculation. It requests approval to use 100% NYMEX natural gas futures instead of 50% natural gas and 50% oil in its pricing formula. It also asks to substitute the fixed basis already included in the formula with either the actual hedged basis cost or, if necessary, another rate approved by the Commission. In discussions with MNG, it appears that it intends to hedge basis costs. As with the IPO calculation, MNG has stated that this formula will provide a better representation of its actual cost of gas than the previous formula. As it has been doing in the past, MNG will use the NYMEX contract settlement date to set the price of gas.

As with the IPO, we concur that the change in the formula to use the NYMEX natural gas futures only is reasonable and should result in gas rates that are closer to MNG's actual costs to provide gas to its customers. Regarding the basis, we agree that MNG should use the contract price for hedged basis where applicable. If for some reason MNG does not contract for basis prior to a specific FPO period, we will require MNG to calculate basis for the FPO based upon an average of the weighted actual basis at Dracut for similar periods over the prior two years. If after making this calculation, MNG has reason to believe that the results are not reflective of the upcoming period, when it files its FPO rates, it can propose other methods along with an explanation as to why the historical basis would not be suitable.

b. FPO Term and Enrollment Periods

Currently MNG offers a monthly enrollment period where each month its customers may enroll in the FPO for periods of 3, 6, 9, 12, 15, 18, 21 or 24-month terms. [2] MNG proposes now to reduce the enrollment period to once annually for a term of either 12 or 24 months.[3] MNG states that because of the limited number of customers and the associated volumes it is not able to hedge its gas for similar terms and therefore, has a greater risk of its actual costs not matching the rates it is charging its customers. In addition, if not enough customers with the necessary volumes elect the 24-month term, MNG reserves the right to eliminate that option.

While it is generally preferable to give customers choices, it is not always possible. It is apparent that it is not feasible for MNG to offer the broad range of FPO terms given the current volatile market conditions and the small volumes that these offerings attract each month. In reviewing MNG's proposed change, we noted that the majority of customers who had signed up for the FPO elected the 12-month term. Therefore, we will allow MNG to reduce the length of the enrollment period to 12- and 24-month terms. We will also allow MNG to eliminate the 24-month term when not enough customers sign up for this option.

Regarding the enrollment period, we will allow MNG to hold one month long enrollment period during the month of August for service commencing September 1, as proposed in its February 13, 2004 update. This provides a longer sign-up period than it currently offers. This seems appropriate if MNG offers the FPO

[2] MNG agreed that deferral of a decision on its FPO proposals until the end of March would not pose a problem because there were only a few customers whose FPO options ended in March.

[3] In its initial proposal, MNG proposed to have two enrollment periods per year and offer six and twelve month terms.

only once each year. In addition, MNG has stated that it will allow a 30-day grace period for residential customers who wish to enroll in the FPO.

In its February 13, 2004 filing, MNG indicated that it will provide a fair transition by grandfathering all existing FPOs until their respective expiration dates, with options for residential customers and small users to elect either to join the then existing FPO or take IPO service. MNG states that large users will have a more limited choice, depending upon the time at which their FPOs expire. If MNG's large users FPO will expire and they will not be able to take FPO service until the next enrollment period, we will require MNG to notify those customers and give them the option of enrolling in the next FPO filing without penalty for terminating their current FPO early. Otherwise, these large users may be subject to more volatility in the price of their gas then they would if MNG had not proposed these changes.

MNG's written proposal was silent as to what options new customers coming onto its system would be given. For new residential and small commercial customers that would not upset the balance of MNG's gas purchasing, MNG could allow those customers to sign up for either the remaining term of the FPO or the monthly IPO. For larger customers, we will allow MNG to use its discretion in the pricing mechanisms it offers.

B. <u>Reconciliation</u>

In its December 12, 2003 filing, MNG proposed that its revised IPO and FPO pricing mechanisms include a true-up provision to reconcile actual gas costs with the price charged to customers. MNG stated that it would compute the true-up amount after subtracting from the total monthly gas cost that cost associated with negotiated rate contracts. It will then compare the remaining amount with the amount charged to its IPO and FPO customers. The difference would be subject to reconciliation. MNG would then allocate that difference to its IPO and FPO customers based on the proportional volume share of each pricing option.

Initially, MNG proposed that for IPO customers, the true up would occur in the bill two months following the sales month. A final reconciliation would be done for the 12 months ending in July each year. For FPO customers, MNG would track the true-up balances monthly but would apply the net true-up basis annually. Consequently, next year's FPO price would include the estimated cost of gas for the upcoming period as well as an adjustment for the true up of the past year's FPO. MNG would maintain a deferred gas cost account on its books to track these adjustments.

Subsequently, in its February 13, 2003 filing, MNG revised its reconciliation proposal to have annual reconciliation only, reflected in bills commencing September 1 as a rate for recovery of over- or under- collections accruing during the prior July 1 through June 30 period. MNG also proposes that a transitional reconciliation for the period February 1, 2003 through June 30, 2003 be allowed.

Both MNG's initial filing and its updated proposal were silent as to the accrual of any interest on the over- or under-collections.

The February 13, 2004 filing included confidential attachments showing MNG's proposal for calculating true-up amounts. MNG proposed initially to calculate a "normalized cost of gas." Then from this normalized cost of gas, MNG would deduct the cost associated with the negotiated service contracts. The remaining cost would be allocated between IPO and FPO customers as described earlier.

In the last technical conference, MNG pointed out that the details on how the cost of the gas remaining in the pipe as well as how the cost of the different contract gas purchases would be allocated to all of its customers would have to be clarified prior to the finalization of any reconciliation calculation.

IV. ANALYSIS

A. Authority

The Commission may approve any reasonable alternative ratemaking mechanisms for gas utilities "to promote efficiency in operations, create appropriate financial incentives, promote rate stability and promote equitable cost recovery." 35-A M.R.S.A. §4706. In doing so, it must consider appropriate consumer and competitive safeguards. 35-A M.R.S.A. §4706(4). Its other considerations may include: "the costs of regulation, the benefits of the rate plan to the utility and to ratepayers, the impact on economic development, the reallocation of risk between investors and ratepayers, the development of a competitive market for gas services that are not natural monopolies," and any other relevant factor. 35-A M.R.S.A. §4706(1). The Commission may, as part of an alternative rate-making mechanism, waive or modify the statutory cost of gas adjustment clause requirements (contained in 35-A M.R.S.A. § 4703) "to the extent necessary to promote efficiency in operation, appropriate financial incentives, rate stability or equitable cost recovery." 35-A M.R.S.A. §4706(8). The statute further provides:

> Prior to the adoption of a new or replacement alternative rate plan or renewal of any existing alternative rate plan, the commission shall, in order to ensure that rates at the starting point of the plan are just and reasonable, conduct a revenue requirement and earnings review under pursuant to the standards of section 301. In conducting such a review under this subsection, the commission, at its discretion, may conduct the review in a manner designed to minimize the cost of the review to ratepayers.

35-A M.R.S.A. §4706(3).

B. Prior Revenue Requirement and Earnings Review

The OPA argues that the Commission may not approve MNG's reconciliation proposal without first conducting a revenue requirement and earnings review for two reasons. First, OPA argues that gas cost and revenue reconciliation is such a substantive departure from the rate plan originally approved by the Commission that it amounts to a "new or replacement alternative rate plan" under Section 4706(3). Second, OPA argues that the expiration of MNG's current rate plan on March 31, 2004 is sufficient to trigger the statutory requirement for a revenue requirement and earnings review because the Commission will need to either renew MNG's current rate plan or approve a "new or replacement" rate plan for MNG's operations going forward.

MNG argues that its reconciliation proposal does not trigger the revenue requirement and earnings review provision of Section 4706(3) because the alternative rate plan – a 5-year rate freeze -- applies only to MNG's distribution, not commodity, rates. MNG argues that while the Commission approved MNG's IPO and FPO pricing formulas for similar reasons, e.g. "to ensure that MNG's risk of investment in its start-up system fell on shareholders, not ratepayers," it did not subject these elements to a freeze. MNG suggests that the revenue requirement and earnings review is necessary only for those aspects of rates that will fall within the proposed rate plan. Accordingly, MNG argues that because it is seeking only to change commodity portion of its rates, the streamlined review of MNG's historic commodity earnings that has already been accomplished in this proceeding is adequate to satisfy the requirements of Section 4706(3) in this instance. MNG argues that this is consistent with the Legislature's underlying purpose in adopting Section 4706, which was to promote the availability and expansion of natural gas service in Maine by allowing the PUC flexibility to streamline regulation, including cost of gas adjustment mechanisms.

C. Decision

The preliminary question that we must decide is whether we must conduct a revenue requirement and earnings review of MNG's total operations at this time, prior to considering its reconciliation proposal. OPA argues that there are at least two bases for us to conclude that the statute requires that we must. The first is that MNG's reconciliation proposal triggers the statutory requirement to conduct a revenue requirement and earnings review because it amounts to a new or a replacement rate plan. The second is that the statute requires the Commission to conduct a revenue requirement and earnings review when MNG's 5-year rate plan expires, on March 31, 2004.

Alternatively, we might conclude, as MNG argues, that we are free to consider MNG's reconciliation proposal at this time either because 1) its reconciliation proposal does not constitute an element of MNG's alternative rate plan triggering the requirement, or 2) its proposal does trigger the review requirement of Section 4706(3) but these requirements have already been fulfilled in this proceeding consistent with legislative intent.

We begin by identifying the components of MNG's rate plan and whether the distribution and commodity rate structures should be weighted differently in the application of Section 4706. We find the elements of MNG's proposed rate plan described in our Order at page 2 under the heading "Shareholder Risk." The elements explicitly authorized by Section 4706 appear to include:

- flexibility to enter into contracts for services without prior commission approval (§4706(5)(B)),
- non-reconciling IPO and FPO commodity pricing mechanisms (§4706(8)) with the exception of upstream capacity costs which the Company may seek rate changes pursuant to 35-A M.R.S.A. §307, and
- multi-year distribution system rate freeze (§4706(2)).

We note that while the rate freeze provision applies only to distribution rates, there is nothing in the Order that explicitly describes the proposed rate plan as limited to distribution rates only. MNG's argument seems to be based upon the distinctions in treatment that we allowed for commodity rates as compared to for distribution rates.

We find evidence in our Order of August 17, 1998, which outlined criteria by which we would approve a revised rate plan for MNG that contradicts MNG's current interpretation that we did not view commodity an element of its rate plan. In addressing the question whether MNG's gas cost projections were understated we said:

> As in *Bangor Gas,* the condition that investors will bear the risks of project failure eliminates the need for us to ensure that CMP NG's projected gas costs are accurate because ratepayers will not be subject to the risk that rates will be higher than currently projected. If ratepayers were at risk for CMP NG's gas costs, we would require a more complete demonstration of how it would obtain supplemental supplies and what effects this would have on overall gas costs. With the condition of investor risk, however, we need only review CMP NG's proposed resource plan to determine that it is realistic and that it will have adequate gas supplies to provide the service that it proposes.

Docket No. 96-786, Order (Phase 2), (Aug. 17, 1998) at 25.

With regard to the proposed IPO and FPO pricing options we concluded:

> We find CMP NG's proposed rate offerings acceptable and do not believe that a different treatment of gas costs (such as a traditional cost of gas adjustment (CGA)) is necessary. Competition, coupled with the placing of project failure risk squarely on shareholders, substantially reduces our concern over how rates are developed. Customers may decide for themselves whether or not they find the price structure offered by CMP NG attractive before committing to it. We decline here to second guess the entrepreneurial instincts of business developers where the risks of failure to achieve market acceptance do not fall on ratepayers.

Id. at 26.

We also provided the following guidance on necessary terms of a revised rate plan proposal:

> We will grant service authority to CMP NG in all of its proposed project area, if it presents an acceptable revised proposal. First CMP NG should revise its rate plan to assure us that CMP NG's proposal has addressed the concerns we have identified with respect to particular rates, that the rates

> will remain stable over time, and that the risk of errors in project cost or revenue estimates will not be borne by ratepayers. … We insist, however, that – whatever price levels CMP NG chooses to offer – ratepayers not be at risk for rate increases to save investors from the consequences of their own poor projections.

Id. at 39.

Our later Order Approving Rate Plan also made clear that the Company's shareholders would absorb the risks and rewards of its entrepreneurial decisions during the term of the plan and addressed the length of the rate plan term as follows:

> Because of the length of time projected to build the distribution system out to a level where it can sustain itself, we consider five years the minimum term for this start-up entity. The shortness of the term may result in difficult questions regarding the allocation of risk to investors versus ratepayers if the Company seeks a base distribution rate increase for the sixth year. Nevertheless, the proposal does ensure a period of partial rate stability and appropriately places the early start-up investment burden on shareholders. While we might prefer a longer, more comprehensive rate stability mechanism, this proposal offers something of value. Thus, we accept the 5-year base distribution rate freeze term.

Docket No. 96-786, Order Approving Rate Plan (Dec. 17, 1998) at 4.

On the basis of the statements in our prior orders, and as argued by OPA, we conclude that commodity pricing was clearly considered an element of MNG's rate plan when it was approved and the degree of scrutiny we accorded its gas supply and commodity pricing was more limited than it would have been if shareholders had not borne the risks of errors in cost or price projections. Accordingly, we reject MNG's current argument that converting from its original rate structure to a reconciled gas cost rate structure would not trigger Section 4706(3).

We turn then to MNG's second argument that the requirements of Section 4706(3) have been satisfied in this proceeding. Prior to approving the change in IPO formula, we did obtain information from MNG showing its gains and losses during each of its years of operation to date. We did so to satisfy ourselves that MNG was not being given the benefit of rate adjustment only when losses loomed, if it had profited in previous years. However, we have not requested or reviewed information in this proceeding related to MNG's distribution revenue requirements or earnings. If one reads the statute to require a more comprehensive review, or concurs with OPA that such a review is required at the expiration of MNG's rate plan, then we have not fulfilled this requirement.

We have not had the benefit of MNG's views of whether the statute requires a review at the expiration of its rate plan term, particularly if it opts to return to traditional regulation. We do find the statutory language in Section 4706(3) provides a useful indication on this point insofar as it requires a review in instances of the adoption of new, replacement or renewal rate plans. The statute does not explicitly speak to what must be done in instances where the utility reverts to traditional regulation. Nor do we have a clear indication from MNG as to what form of ratemaking mechanism they propose to go forward with at the expiration of this plan on March 31, 2004. Accordingly, we propose to defer further consideration of MNG's reconciliation proposal, which we do find would comprise at least one element of a new or replacement rate plan pending the following actions:

1) that MNG articulate its proposal for what rate-making mechanism it should operate under going forward; and

2) that a further review of MNG's overall earnings and revenue requirement be accomplished.

We encourage the parties to come to agreement on what should be the form and detail of review and note that what is appropriate may depend in some measure on what MNG proposes for its regulatory format going forward. We direct MNG to file its proposal no later than April 20th and request that the parties report to us on their progress by April 30th.

B. Alternative Disposition: Policy Issue[4]

Even if we were to determine that we may adopt a fully reconciled Cost of Gas (COG) clause for MNG at this time without first conducting a revenue requirement and earnings review, there remains the issue of whether such a fully reconcilable clause is a desirable policy.

The arguments in favor of a fully reconciled COG clause are relatively simple. First, gas costs represent a major portion of total costs for MNG, as they do for most LDCs. Thus, significant gains or losses on gas costs can have a very real impact on income. Second, gas costs are primarily driven by the market, particularly changes in the overall cost of gas, typically defined as the NYMEX price for gas at Henry Hub, and the basis differential, which is the difference between the Henry Hub price and the price at a local delivery point such as Dracut Massachusetts. Both elements have shown considerable volatility in recent years. This underlying level of volatility is fully outside MNG's control, although the Company does have the ability to hedge volatility in these markets to a significant degree. Finally, the other two LDC's in Maine currently

[4] This section is included to facilitate alternative disposition at the Commission's option.

have fully reconciled COG clauses. This could be read to suggest that MNG should also be entitled to one.

Each of these arguments suggests a counter argument. If the cost of gas represents a large portion of an LDC's costs, then it must also represent a large component of the price to customers. The fact that gas costs are large indicates that it is an item that an LDC should pay close attention to if it is behaving responsibly. However, a fully reconciled COG sends an LDC precisely the opposite message; there is no direct incentive to minimize the cost of gas. In fact, with a fully reconciled clause, an LDC's largest direct exposure would probably be that we might disallow of an expense as imprudent. Where that is the case (or where an LDC believes that to be the case) then a reconciled clause can provide a powerful incentive to be very conservative in its practices, not to minimize costs.[5] With a fully reconciled COG, the primary protection for customers is an after-the-fact review of gas procurement actions by Staff and, perhaps, by interveners in a future case. But such proceedings are difficult. We prefer to implement regulatory mechanisms, where possible, that exert pressure on the utility to purchase gas in a cost-efficient manner.

Next, while it is true that MNG is a price taker with no ability to influence market prices that does not mean that it has no ability manage the risk. In fact, there was significant discussion of this issue during the technical conferences in this proceeding. MNG's customers purchase gas under either an Indexed Price Option, where the price is fixed monthly based on futures prices at the beginning of the month, or a Fixed Price Option where the price is locked in at the beginning of a longer term

[5] See, e.g., *Northern Utilities, Inc., Petition for Approval of the Use of Financial Instruments as a Part of A Hedging Program, Docket No. 2001-679.*

period, based on the futures prices for that longer period. In both cases, MNG has indicated that it will attempt to purchase gas at fixed prices very close in time to when the IPO and FPO prices are determined. Under this strategy, the MNG can have a high degree of assurance that its gas costs and revenues should track one another closely. Under this strategy, the remaining risk concerns the quantity purchased. For example, when the sell price is determined to be $5.00, MNG will normally be able to purchase gas for the same period at the same $5.00 level or very close to that price. The main risk is determining the quantity to purchase. If MNG purchased 100 units and the actual usage in the month was more, then additional purchases would be necessary and there is no guarantee that the price would remain at $5.00. Similarly, if MNG made the same 100-unit purchase but actual sales were lower at 90 units, then MNG would presumably sell 10 units back into the market. Again, there is no certainty that these sales would occur at the same $5.00 price.

In other words, although MNG appears intent on adopting a hedging strategy, it will still have some volume risk. The question at hand is whether that risk, as well as any residual risk associated with divergent buy and sell prices, should be borne by MNG, its customers, or both.

We believe it is desirable to have at least a portion of the risk be borne by MNG. MNG will be making regular decisions about managing its gas portfolio and each decision will have some effect on the overall risks of that portfolio. We believe it is a better policy to have MNG make decisions based on its own self-interest rather than based on what it believes it will produce the smallest likelihood of a cost disallowance. We also believe that this can be accomplished by a partially reconciled clause which avoids exposing MNG to levels of risks which could, in a severe case, eliminate or double its profits for a heating season.

Accordingly, should reconciliation for MNG move forward, we would not approve full reconciliation for MNG. Rather, we would instead implement a sharing mechanism with an annual bandwidth of plus or minus 2½% around any reconciliation. In other words, if over the course of a rate year, MNG's gas revenues were between 97.5% and 102.5% of its gas costs, there would be no reconciliation. However, to the extent that there was a larger diversion, then over-collections would be refunded to get back to 102.5% or under-collections recovered in order to get back to 97.5%. This bandwidth is small enough so that there will not be large earnings swings but also large enough so that MNG will be uncertain as to whether the bandwidth will kick in and therefore act as if it had its own money on the line.[6]

At the time we approved MNG's and BGC's rate plans, we also approved competitive franchise areas for gas utilities, having concluded that natural gas in Maine competed with other alternative energy sources, primarily heating oil, but also electricity, propane, wood, and other LDCs. At that time, we believed that the market would "discipline" LDC's, such that competitive pressures would spur utility managers to keep gas costs low. We recognize also, however, that once

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[6] The Staff, MNG, and OPA discussed this approach at a technical conference. On February 13, 2004, MNG reported:

> After extensive internal review and discussion, MNG has determined that it cannot accede to an incentive bandwidth in the reconciliation mechanism. Nonetheless, the Commission's annual review of the reconciliation calculation, in which the Commission can adjust for imprudent purchasing costs, adequately protects customers from unjust and unreasonable rates.

customers convert to natural gas "reconversion" costs restrict their ability to take advantage of competing energy sources as prices fluctuate. Consequently, there may be less direct incentive for LDC's to minimize gas costs for its established customer base. Implementing a gas cost incentive mechanisms provide economic risk, prompting managers to focus on gas purchasing costs.

Finally, there is the question of why MNG should have a partially reconcilable gas clause while Northern Utilities, Inc. (Northern) and Bangor Gas Company (BGC) have fully reconcilable clauses. As to Northern, we note that the statute only allows less than full reconciliation as part of an alternative rate plan and Northern, to date, does not have such a plan. BGC presents a different picture. About five years ago we approved alternate rate plans for both MNG and BGC as part of the start up for those then new LDC's. MNG specifically proposed not to reconcile gas revenues and costs. When we approved MNG's rate plan we noted that the Company's willingness to accept this risk was a positive element of the overall rate plan. BGC, on the other hand, requested and was granted a reconcilable gas clause within the context of its own overall rate plan package.

The Commission and Staff have followed the activities of both companies, including their gas procurement activities, over the ensuing years. In general, we believe that a reconcilable gas clause does not provide strong incentives to focus attention on fuel procurement. That becomes part of our basis for recommending a partially reconciled cost of gas adjustment clause here if MNG's proposal to implement gas cost reconciliation moves forward.

IV. CONCLUSION

Because they do not change the allocation of risk between shareholders and ratepayers and are within the scope of changes to upstream capacity costs envisioned in our original Order Adopting Rate Plan, we approve changes to the FPO and IPO pricing option formulas consistent with changes we allowed to the IPO formula in our January 14, 2004 Order.

We also approve changes to the FPO option to limit this offering to either a 12-month or 24-month term beginning on September 1st each year. Again, because shareholders are at risk for commodity costs, we view this as an area for entrepreneurial decision rather than one requiring regulatory oversight.

We defer consideration of MNG's reconciliation proposal until MNG provides further articulation of its proposal for regulatory rate-making mechanism to apply to it after expiration of its current rate plan on March 31, 2004 and to offer its views on whether a revenue requirement and earnings review is required upon expiration of the current plan. We also direct the parties to attempt to find agreement on the form and detail of any necessary revenue requirement and earnings review.

Finally, we find that such a review is necessary if MNG seeks to pursue approval of this or any commodity reconciliation proposal.

Respectfully submitted,

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Carol A. MacLennan
Hearing Examiner

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